CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

FUELS AND TRANSPORTATION COMMITTEE WORKSHOP

GULF COAST TO CALIFORNIA PIPELINE

FEASIBILITY STUDY

HEARING ROOM A

CALIFORNIA ENERGY COMMISSION

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Valorie Phillips

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COMMITTEE MEMBERS PRESENT

James D. Boyd, Commissioner, Presiding Member

Susan Bakker, Commissioner Advisor

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Drew Laughlin
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I N D E X

P R O C E E D I N G S

PRESIDING MEMBER BOYD: Good morning. Isn't this part of our continuing series -- no. Good morning -- well, the audience is looking real familiar, anyway.

Good morning. I'm Jim Boyd, the Presiding Commissioner or Member of the Fuels and Transportation Committee, and I want to welcome everybody to our workshop today. Today's workshop is relative to the feasibility of a Gulf Coast to California Pipeline.

We're going to discuss today the -- in this workshop, this Committee workshop, the contractor's work and the Staff's work regarding the feasibility of financing, constructing, and maintaining a new pipeline, or utilizing or expanding the capacity of the existing pipelines to transport gasoline, other products, gasoline components, so forth, from the US Gulf Coast to California.

This, again, is work the Commission is doing as a result of a legislative request, in this case Assembly Bill 2098 requested that this work be done. As in previous legislative mandates, which we seem to have a lot of these days, the Commission has retained outside help to assist in this work. In this case, we've retained Interliance, Incorporated, and Drew Laughlin, to assist in doing the evaluative and the feasibility work that was requested of the Commission by this particular Assembly bill.

Once again, I have to recognize for the audience and the interested public that not a lot of time has been provided to you to review these -- the contractor report, and a lot of people, I'm sure, would like more time. So, as yesterday, I'm probably going to chill the participation of the audience today by mentioning that we're going to give folks more time, and we will probably have an extended comment period and yet another workshop in this subject in the not too distant future, in order to be fair and square and provide everybody as much time as possible.

So hopefully, in spite of that extension of the tax deadline date, so to speak, folks, we can still have a meaningful discussion of the subject today, and everybody want to hold back until the last possible moment, i.e., the next workshop.

So again, I ask everybody to listen

intently, along with us, to the presentations, and then have a dialogue following those presentations on the reactions and feelings, so far. And then we'll proceed to have another discussion in the not too distant future, time to be established.

Again, for anyone listening in to this via the Internet on the Webcast, the report, the draft report that we're dealing with today -- or reports, I should say, plural -- are on the Energy Commission's Web site at www.energy.ca.gov.

So with that, I'll briefly go over today's agenda. And then we'll proceed with the workshop.

It's anticipated that between now and the lunch break we will have first the contractor presentations. Secondly, presentation from the Staff around noon. A lunch break, roughly an hour, again, and then convene after lunch for a hoped-for public and stakeholder question/discussion/comment period, and what have you, and then wrap up for closing remarks.

With that, I think I would like to turn the presentation over to our contractors. And I'm not quite sure to whom I'm going first, Pat.

MR. PEREZ: Mr. Laughlin.

PRESIDING MEMBER BOYD: Mr. Laughlin.

MR. LAUGHLIN: Can you hear me? Good morning. I'm Drew Laughlin. I've had 25 years' experience in the gasoline blending business, and the supply and distribution and trading on the Gulf Coast. Formerly with Valero, and I've owned my own company up until a few years ago, and now I've become a consultant basically doing issues, supply issues like this, on the Gulf Coast, and MTBE issues.

This morning we have a number of reports. Two of them, one is a supply off the Gulf Coast, and the other one is the distribution report, basically regarding waterborne distribution, particularly Jones Act vessels, and supply, or lack of supply, of vessels to move product to the West Coast.

This particular report will go over the refinery capacity assessments from the Gulf Coast, import assessments, and issues that could impact supply. And I want to stress in the beginning, the system in the United States is basically a well-balanced system. What we do in the West Coast will affect what happens in the Gulf Coast and on the East Coast, and that's, if you come away with anything today, an understanding of how balanced this is, and how the balance will change as you change your supply specifications on the West Coast, the need for imported product on the West Coast, how things will re-balance in the future.

We're going to estimate spare capacity on the Gulf Coast, which you'll see is relatively limited. We'll also be talking about the ability of current refineries to supply product to the Tucson/Phoenix area via soon to be the Longhorn Pipeline. There is a current pipeline,the Orion Pipeline, also. Plus, of course, there are refineries in the region, in the El Paso area, and in the New Mexico area. Then, of course, the refineries on the Gulf Coast.

I also want to go over briefly, we'll be talking about the petrochemical business and how it relates to gasoline supply. And it is an important factor, not as much important in total numbers to the total US gasoline supply, but relative to California's demand for ultra-clean product, it is very significant.

We're going to be talking about -- as you'll see in a moment -- the crude units, FCC units, hydrocrackers, cokers. Essentially, what you're going to see is, if you were here in the MTBE meeting a couple weeks ago, that they're essentially full. The capacity on the Gulf Coast hovers usually around 90, 95 percent, to a degree the same as the West Coast, but not as much utilization as it has been on the West Coast. Your system out here is tweaked to the max.

Gulf Coast crude units. As you can tell, in the last ten years utilization has risen substantially to where we're essentially at a 95 percent rate most of the time. And this is on a calendar basis.

FCC units. FCC units, as you can see, are running over calendar rates most of the time. And an important note I'd like to make here is most of the FCC gasoline in the Gulf Coast is a high sulfur gasoline. And even what we consider low sulfur, which is three and 400 ppm, on the West Coast would be considered unusable.

Gulf Coast hydrocrackers, the same thing. At this point those that have hydrocrackers are essentially full. A few more, I understand, are being planned, but this is, as we get into 2005 desulfurization, I think we'll see more expansion here.

Gulf Coast cokers, the same thing. More cokers are being built. Essentially, though, we're at capacity.

This chart I want to go over in length. This is an important chart. What's happened over the last ten years is you can see FCC capacity has creeped up. Coker capacity continues to creep. Alkylation capacity is flat lined on us. What's happened here. This is the ratio of alkylate to pet gas and coker capacity. What's happened here, it's been easier for a refiner to increase cracker capacity, and coker capacity. What they'll do is they'll take their olefins into an existing alky unit here, but the cost of building a new alky unit is substantial, $80 million, $69 million, just for a 15,000 barrel a day unit.

What's happened in the past is MTBE was produced, and propylene was taken out of the alkylation pool. The refiners would decide basically to take propylene out or isobutylene out, and sell it either into MTBE market or use in the MTBE market, or sell the propylene into the chemical market. Essentially, not building any further alkylation capacity.

And the important point here is for California, this is the most important line. We need alkylate in California in order to make CARB type fuels. Another point is as capacity has gone up on both coker and FCC capacity, the supply of pet gasoline and coker naphtha has risen, of course. That is a relatively dirty blendstock. That blendstock has had have been diluted with alkylate, but we have less alkylate. And at the same time that California needs alkylate, the rest of the country is essentially desiring the same barrel. And that's the point I'm trying to come across with, is that this line right here is major problem.

So refineries are full on a calendar day basis. What does that mean? Can we get more barrels? The answer is yes, we found recently that on a stream day basis, everybody's been running at higher rates. They have not had the shutdowns or turnarounds to the degree that they had planned, so it looks like on a calendar day basis they can squeeze a little bit more out of it.

When everybody runs basically at this point we seem to have an oversupply of conventional and RFG fuels, along with considerable imports coming into the country. And I want to stress the point conventional and RFG, not CARB. The Gulf Coast refineries are at this point capable of making CARB II. A few, let's say two to three refineries have done it and brought product out to the West Coast. A few refiners are probably capable of making CARB III winter grade, and to this point, no one has stepped up and said we're capable and ready to make CARB III summer grade, which is where we see the short-term problem in the next few years.

If we're talking about refineries, as we've seen in the past, in the last two months, refinery margins were slim. Some of the refineries shut back production. As they shut back production, margins and demand come back in place. As you'll see, that's why you see, going back three or four charts, why the refinery runs go up and down. It's not just refinery maintenance problems. There are conscious decisions to cut back in order to increase margins. If margins are too low, Gulf Coast refiners have recently, and will in the future, cut back to the point that it makes sense for them to supply the market.

The following, this map shows a point of how the Gulf Coast has literally become the hub and the wheel. We, on the Gulf Coast, now, the Longhorn line is in white. Hopefully it's not going to be the ghost line that it show sup there. But the, as you can see, other lines going into the general area, the new Centennial line going up to Chicago is significant. As it has come online, it's I assume one of the reasons why Premcor has recently announced the future closure of the Hartford refinery. And has, of course, has already closed Blue Island.

The Explorer line is a major line taking product to the midwest. The Colonial line, which is going to be a subject of our conversations in the rest of the afternoon here, is the major line moving product up to the East Coast, along with Plantation.

As you can see, product comes from the Gulf Coast from essentially the Louisiana area all the way over to Corpus Christi, and there is tremendous amounts of flexibility in this system here, not just between refineries but petrochemical plants, LPG plants, facilities, loading docks, terminals. This infrastructure is really set up for maximum flexibility.

How it works. As you know, product prices, high prices will pull product towards a region, and low prices will repel it away. This is the balancing act that happens in the entire United States. As product prices in a region go up and down, the Gulf Coast refiners or the midwest refiners, or East coast refiners will react to these different price changes.

As I said, north Texas refineries can go essentially south to El Paso, northwest up to Denver, through a number of different lines, but most of the time stay in the local region, or go up towards the mid-continent, as they do today. US Gulf Coast product economics impact El Paso by either pulling or repelling product from north Texas refineries. Again, the balancing system we're talking about. Products can go from the Gulf Coast to virtually any region that's supplied by pipe out of the Gulf Coast, depending upon the economics of pulling them into that region.

And for anybody who's following on the Webcast, we're on page 13.

Midwest gasoline prices. This is just

an example of what happened two years ago, when we had problems in Chicago. They soared in the spring of 2000. Local supply couldn't keep up with the demand, as many problems occurred. One of them was the first, we had winter/summer RVP changeover. We also had a number of refiners who were making, it was easier to make conventional gas, and as they were having problems made more conventional gas than RFP. And then found out later on that they were short one grade and long in the other.

We didn't have a volume extension due to ethanol blending in that period of time, similar to a problem that you'll see in California in -- when we do the MTBE ban in some point in time.

When Explorer pipeline broke, obviously there's nothing you can do. Prices just took off, and product couldn't be supplied. This -- the point I'm trying to make here is Chicago has acted as a mini-lab. As we look at Chicago over the last couple of years, it looks a lot like what California may be in the future. It's basically up the pipeline, hard to reach, it has refineries but when refineries have problems it's very tough to recover sufficient supply and get it into the area fast enough to avoid major price spikes.

We'll go over New England states are supplied by local refineries via pipeline and the waterborne material off the Gulf Coast. And you see spot differentials move product back and forth between different areas of the United States, you'll see how the system works.

These are the pipeline tariffs. This a one that may be a little hard to see for you all, but this is the gasoline chart on basically Gulf Coast differentials versus New York Harbor differentials. The pipeline tariff there in the pink essentially, at this point here, it's worthwhile for a Gulf Coast refiner to ship product up to New York Harbor. And there are some grade changes. This is a simplistic way of looking at things, so I want to make sure everybody understands it's not just conventional versus conventional, but there are some grade differentials.

The essential point is that when these numbers here reach above this line, Gulf Coast refiners start to move product up here. There is a lot of variation in this. This, there's a lot of seasonality here, too. This is grade changeovers, and it's always in April. As this happens, basically product will move up to the New York Harbor area in the summer. And we've seen that in the past.

This is a chart between the Gulf Coast on distillate and New York Harbor. As you can see, again, this line, that very little product actually will stay in the Gulf Coast under these circumstances. This -- almost always, the product, the distillate product, the market for especially home heating oil, is up in the Harbor, so it obviously moves to the Harbor more often than not.

Jet fuel. As you can see, it virtually never goes below the line. This is an important graph here, because as one of the comments yesterday, that we talked about in the meeting yesterday, was what happens when you have a completely fungible product. And this is -- and there are five or six different grades of jet fuel, but essentially there are small differences in sulfur.

When you have a product that's fungible, when you have a product that has multiple players with lots of tankage, you basically get a very efficient market. Product moves in from all over the world into this market. The barriers of entry are minimal, and you have a system that essentially works.

New England refineries are supplied by local refineries up in the New York Harbor area, and a great deal of imports into the East Coast. In addition to that, there's the Colonial Pipeline, and pipelines that enter the New York Harbor area from the Gulf Coast.

Spot differentials below the pipeline tariff obviously will repel product. Meaning basically, a Gulf Coast refiner has no reason to ship a product up if he can't make at least pipeline differential, so that product would just simply stay in the Gulf Coast.

More imports, again, would repel product to the Gulf Coast, basically driving the market down in New York Harbor. Product would just simply not pump up the Colonial Pipeline. And this is part of the entire balancing system we're talking about.

The Central Atlantic states have similar situation to New England. Again, they're supplied by the pipeline, and as the pipeline goes up through the Maryland area it can drop off product, so it is not as much of an island as, let's say, the lower Atlantic states are. Georgia, or at least south Georgia on the coast, and Florida have essentially no pipelines. The significance there will come into play not just in this study, but in the next one on marine movements, because a great deal of Jones Act shipping is utilized moving product from the Gulf Coast to Florida and Georgia.

MS. BAKKER: Drew?

MR. LAUGHLIN: Yes.

MS. BAKKER: I don't know if this is the case for other people, but our slide 18, or my slide 18 is missing from the packet.

MR. LAUGHLIN: If you have a package, you're probably one of the few, I think. It hasn't been --

MS. BAKKER: Oh, okay.

MR. LAUGHLIN: -- printed.

MS. BAKKER: We haven't -- okay. I do have a package.

MR. GANERIWAL: That might be from last night.

MR. LAUGHLIN: This is just a slide that

shows how product coming from Gulf Coast refineries essentially serves the Tampa market, the Miami market, Jacksonville market, Savannah, Wilmington market. And then additional product will go to the Harbor as product prices demand. But the most important market for Gulf Coast waterborne is the lower southeast United States.

As you see, in this graph it shows pipeline movements -- or, excuse me, waterborne movements from PADD 3 to all other areas. And here, when it says "CA", it is not California. That's Central Atlantic. LA is not Los Angeles, but Lower Atlantic.

This basically shows the tremendous amounts of product that has to move in order to keep those states supplied.

We'll go into petrochemical demand for a few minutes. Demand for petrochemical feedstocks affects refinery supply. And what happens here is, again, the refiners' ability to maximize profits have moved them into the petrochemical market in many areas. A refiner can simply say today whether he would like to alkylate his propylene, or sell it into the chemical market.

Products such as LPG, ethane, propane,

butane, natural gasoline, naphthas, condensate and gas oil, all of these are ethylene cracker feedstocks. And some of these, particularly butane, natural gasoline and naphtha, are also gasoline components and/or direct blendstocks. The competition between chemical units for feed and gasoline blenders for blendstocks, and refiners for feed in the naphtha case, is constant, every day.

As demand for petrochemicals increases, these products leave the refinery blendstock and feedstock pools. The chemical business, when it is cranking -- and today it is not, it is hurting -- it takes a tremendous amount of product away from the gasoline pool and the refining market.

PRESIDING MEMBER BOYD: Drew.

MR. LAUGHLIN: Yes.

PRESIDING MEMBER BOYD: That point about the chemical industry, let's say, hurting, I mean, this point you're making now gets back to a point that's been made almost repeatedly in these various workshops, and a point that's really stuck in my mind since it was made in the very first discussion of the market and the MTBE issue. And that is the demand for what may be becoming a higher quality, higher priced constituents. And you mentioned the market's down now. Is it down in correlation to just the general recession?

MR. LAUGHLIN: Yes.

PRESIDING MEMBER BOYD: And will it recover accordingly? Is it fairly linear with regard to the improvement in the national economy, or is the chemical industry on the verge of seeing a real resurgence that possibly will outstrip the pace of recovery, or vice-versa?

MR. LAUGHLIN: It seems to go more towards manufacturing recovery than just the general economy. But the belief is that by the end of this year, assuming recovery in the US economy, that the petrochemical market particularly -- the one that comes into play the most is propylene -- particularly in propylene, will be able to outbid the refining market even in a high-priced alkylate, and take that product back into the chemical market. That is where it has been traditionally, 19 of the last 20 years. And probably should be 19 of the next 20 years.

PRESIDING MEMBER BOYD: Because you can see where I'm going, where I went in the first workshop, is an even -- a new concern for, you know, gasoline supply because of the competition that's maturing, so to speak, in this -- in the chemical markets and the demands that have been made on the barrel of crude oil, and the ability of the economics to keep it coming towards gasoline versus chemicals. And I guess I'm getting worried that that's just a major compounding issue with regard to the ability of the nation, not just California, to have adequate gasoline stock.

MR. LAUGHLIN: Jim, it is, and Murphy's Law says exactly the right time when California needs it, more than likely the petrochemical industry will be there, too, at the same time, to take it. That's really my biggest concern, too. this is such a different supply/demand issue in California versus the rest of the country, and that's a point that people need to understand, is that the desire for CARB fuels and the requirement that it has such ultra-clean characteristics, it basically takes the peak of the pyramid, it's the top quality material, out of the rest of the country.

And as you get into that ultra-clean product, it competes, you know, not just with other areas of the United States, or other areas of the world, it competes with other industries. And then that's the point that the refiners do realize, but in choosing profit, which is the normal thing to do, they'll go to the highest net back market. And that will normally be the chemical market.

PRESIDING MEMBER BOYD: Ultimately, as goes California so goes major parts of the nation, too, I trust.

MR. LAUGHLIN: Yes.

PRESIDING MEMBER BOYD: We just get it first. For better or for worse. Thank you.

MR. LAUGHLIN: This is petrochemical competition. As we just said, petrochemicals, usually when the competition between refinery feedstock and petrochemical feed, the following two slides will show you this, propylene, again, this is what we've talked about. The propylene alkylate is an important alkylate. It isn't the only alkylate. We make alkylate from butylenes, and also in the future I think you'll also see amylene alkylate.

The problem with butylene alkylate, it is slightly -- I'll say slightly heavier than

California would like to have it. It can be blended down to meet California specs, but the cost there is usually octane. The amylene alkylate is so heavy that when it's introduced into a refinery stream or a mixed alky stream, it will more than likely drive that alkylate midpoint up to a point that it's not going to be usable as a California blendstock.

The reason I just want to show this slide is this is just a basic building block in the petrochemical business. And the point I'm trying to make is that the yellow areas are propylene. And as you can see, in almost every product, and as we go downstream in the chemical business, propylene is involved. And as the demand for finished goods goes up in the United States, the demand for propylene ramps up. And it does so sometimes exponentially.

Again, this is just one more chart showing plastics use, or showing propylene in the chemical business.

Propylene and butylenes are used to make alkylate. Both olefins can be used, and also, again, don't forget C5s, or pentylenes, which in the future I think will be used in some of the alkylation units too.

These are basically essential for the production of alkylate or iso-octane. These can offset, or alkylate can offset the ethanol RVP, as many other products can, too. But one of the keys to alkylate is its cleanliness. It has virtually no olefins, no aromatics, it's all paraffins. It's virtually low sulfur and low RVP. It's used to dilute dirtier burning components. And I need to stress that for a second, because this is the balancing we're talking about on a worldwide basis.

We have product today coming into New York Harbor from worldwide resources. We've seen product recently come from China, come from Russia, and the product is not as clean as we have it in the United States. It doesn't meet an RFG spec or a conventional spec. A blender or a refiner up in the East Coast will then take that product and blend it with a clean product. The one of choice is usually alkylate, but there are many others. Reformate, toluene, many products come into play.

But the balancing act requires that as more dirty product enters the United States, the demand for cleaner blendstocks in New York Harbor goes up to balance that material off, and it's simply a math problem. If the product can come in here from anywhere in the world at a serious discount to the harbor, it raises the differential that a blender would pay for a product to balance that material off to make either an RFG or a conventional gasoline in the East Coast.

As you'll see in a minute, the refining sector is the swing source of propylenes for petrochemical use. But the refining area is the dumping ground for butylenes. I should try to explain this.

As I said, propylene is usually more valuable as a petrochemical feed than as a gasoline alkylate blendstock. The reason here is that propylene, one propylene plus 1.6 iso, and this formula has many variations, some say 1-3, some say 1-4, so -- and the bottom line is, there's a serious volumetric loss whether you use -- no matter how you do it, whether it's 2.6 gallons or 2.5, you're only making 1.8. Part of this is just the loss as you combine the molecules. But it impacts -- this isobutane molecule here is important, when a refiner's trying to develop a -- he has an LP evaluating whether he's going to take propylene into chemicals or into the gasoline pool.

The value of alkylate in gasoline, of course, influences the value of propylene, and the price differential between isobutane and gasoline could dramatically affect the value of propylene to alkylation.

Refining, as I said, is the swing propylene source. This is refining share on the right side, you'll see it essentially has gone up from about 48 percent to about 52 percent. Essentially, we're seeing more refinery grade, which we call PP, propane propylene, entering the petrochemical market.

This is that amount of refinery material which is coming in to the refining pool, or, excuse me, from the refining pool. This is the propylene that's made on purpose from the petrochemical industry.

Butylenes. As you can see, butylenes are right at and actually above. We're producing more butylenes than alkylate can handle at this point. Again, this comes back to alkylation capacity has not expanded. The butylenes essentially come from the refining industry. This comes from the ethylene cracker and through the petrochem industry, and the small blue section is from -- and you probably can't see this out there, but it's the dehydro business. This is essentially the business that's on purpose production of butylenes, for the most part, for the production of MTBE.

And this, that shaded area there, in the future has to decide what's going to happen to that when MTBE is banned, potentially nationally. This material may change into some other type of component, such as iso-octane, but the future of this material is unknown at this point, in the future.

Petrochemical butylene supply exceeds petrochemical demand. Essentially, the petchem market for butylene, it just does not use what it supplies. It doesn't, it's not as the propylene, it's not a building block for as many products as propylene is.

This is butylene demand. Again, it -- how it -- it goes to alkylation, to the MTBE unit, some to the petrochemical business. But the petrochemical business here is not really significant. This section is, to the MTBE units, again, this material here is going to change in the next few years depending upon what happens to MTBE production.

Essentially, propylene and butylene has to go somewhere. The economy sets the petrochemical demand. The petrochemical producers can reduce production by shifting to lighter feeds. What I mean here is if, for instance, propylene gets too long in the market, a ethylene cracker can simply switch to ethane and make considerably less ethylene, or considerably less propylene and more ethylene.

Refiners have the ability to change charge rates, and in some cases change conversion. But because petrochem users of propylene are larger than butylene users, with limited refiners, discover that basically they balance their system by moving propylene in and out of the gasoline pool, and into the petrochemical market as margins come back and forth on propylene. But on butylene, they essentially not just absorb their own material, but they absorb material coming from the petrochemical business.

And we were talking about the growing

economy. What happens with alkylation capacity and balances. This essentially is showing what's feeding the alky units, and what's going to happen in the future. The dehydro C4 again, this is the on purpose production. This material, this is the entire balance route. This C3 can move in and out, as you can see here. It has been at this range, it's now here, and it's continuing to move out to the petrochemical market. This is the propylene.

This section here, again, it's yet to be determined as to what happens after MTBE.

This chart shows the differential between unleaded gasoline and isobutane. The most important part of this chart is the differential, the red line. The point we're trying to make here, and many times isobutane is equal to no lead gasoline. Because isobutane is a major component in alkylation, whether it's butylene or propylene, alkylate, and you're using 1.6 or 1.5 or 1.8 molecules, essentially it's difficult for a refiner to take these molecules, put them together to make an alkylate.

And what I'm trying to say is when isobutane is close to the price of gasoline, it makes the price of alkylate, or the cost of alkylate essentially much higher. And this is -- and when you're using propylene, and using more molecules of isobutane to make alkylate, it even becomes a more severe situation.

Essentially, refiners, because isobutane is close to gasoline so many times, you ask why haven't they expanded alkylation units. It's hard to justify, essentially. You have to guarantee yourself that you're going to be looking at differentials that we're now starting to achieve in alkylate over no lead of 20, 30 cents a gallon. In the past it was seven and eight cents a gallon alkylate value over no lead.

This chart, if you look at it in the past and you're trying to justify a future investment in alkylate, would really give you a fit.

This is a regional supply chart. This is the refinery grade sales. This line here is the value of refinery grade propylene. Take, for instance, in California. For instance, it's always better to make conventional -- well, you don't have -- you have one dimate unit out here. But essentially, conventional alkylate. Anything else, it says here that in this particular case, propylene is more valuable to the refining sector. In the Gulf Coast, or let's say in Texas, it says the opposite. It says in this case it's better going to chemicals.

And I think the next chart -- this is a really significant chart. The red line, as you can see right there, is only crossed into the petrochemical demand once, which is the one you were talking about the last 20 years. What this line basically says is that the demand for propylene into the refining sector only in one year out of the last -- in this case ten, but the chart actually goes back another ten years -- it was more valuable into the refining side, and that was only because alkylate achieved extremely high values last year. Gasoline values were high last year, and we had a petrochemical basic recession.

That is not the case, and the expected case in the future is this line right here. That it should stay well below its value into any gasoline stream.

Recapping refinery capacity. Refineries are running full on a calendar day basis, but product is available when they all run. Imports into PADD 1 and 2 will free up product that could move to the west from the Gulf Coast. Price competition determines if inland Texas refineries flow east to west, or actually it -- it determines the flow of products all over the United States. If the prices in Chicago or in the East Coast are higher, they'll just pull the product off the Gulf Coast. It'll be backfilled by imports into whatever region, and the region it usually backfills into is the New York Harbor.

And I stress how this works, because it's important to understand there's no reason to bring in import, most of the time, to the Gulf Coast, when it has a higher value on the East Coast. Simply, product moves into New York Harbor, product doesn't ship up the Colonial Pipeline, it's then left in the Gulf Coast. And that's the balancing mechanism.

Petrochemical markets are leaving fuels in the product today, but I don't expect that to be in the future. And certainly not in two or three years.

Import assessment. Historical imports, we'll talk about infrastructure to move these products along the Longhorn Pipeline, and the infrastructure to increase imports in the future. Modifications that we need in the US are fairly small. We are already, on the rest of the United States, capable of taking in major quantities of imports without any problem.

As I said, most gasoline imports go to the PADD 1 district, essentially. This is, PADD 1, of course, is Florida all the way up through the East Coast. Very few would come to the Gulf Coast. It just doesn't make sense.

Most of the imports, where does it come from? As you can see, Canada has a little bit -- this is the East Coast/Canada line down here in green. The Virgin Islands, you'll see in there. But essentially, Western Hemisphere is a major producer of product into the United States.

Significant here, though, is Venezuela I don't believe can make -- has not made CARB II. I don't think they'll be making CARB III. The Virgin Islands has made considerable volumes of CARB II, but to my understanding is -- has said that they have problems, or will have problems making summer CARB III.

One producer in Canada has said that they can make CARB III, but have not ever done it.

And sometimes it's a little more difficult to do than just doing it in the lab.

This one will show product movements, typical to what's happening today. Canadian product essentially ends up in Boston and New York. Just logistically, it just makes sense.

Caribbean product essentially ends up in Florida. Puerto Rico, Puerto Rico is a main source or supplier for the Virgin Islands. It just makes sense, again, logistically. But product from Puerto Rico or essentially the area of -- which would be St. Croix, moves into south Florida and the southern US. They just have a logistical advantage, and they do not have to use American flagships. And they have the only long-term waiver on American flagships.

Product from Venezuela. The Vens now make RFG almost entirely. They used to make both conventional and RFG. Today they make RFG, so it goes into the RFG market, which is essentially New York.

Brazil is a swing producer. We met with some of the Brazilian companies last week. They aren't making RFG, but they're making a blendstock, and they're making conventional gas.

So this conventional gas, it'll go into the conventional areas in the southeast United States. Brazilian product will flow into the States, and there's a relationship that's kind of strange, but sugar prices are important to them. They use 24 to 28 percent ethanol in their gasoline. As sugar prices get up, they will basically make sugar and less ethanol. As ethanol prices move around, they'll put their ethanol in the gasoline.

When they maximize ethanol in the gasoline, they're allowing finished gasoline to move to the United States.

Again, this is their balancing system, but it affects the United States. If sugar prices are low, they'll essentially make sugar, they'll make less ethanol. And they'll actually reduce the volume. They have a system that's very flexible. They reduce the volume of percentage of ethanol and gasoline in Brazil. What it essentially does then is they become a gasoline purchaser, and their market has opened up in the last few weeks where they are now legally allowed to do that. So they will swing back and forth in the future, from being a supplier to being a buyer.

Europe is a significant supplier to the United States. Direct imports into the southeast and to Florida have been the ties, but most of it goes into New York Harbor and it's re-blended.

California post MTBE ban at some period of time, when this comes in. We basically have barrels coming from Europe, barrels coming from Canada and the US Gulf Coast, and this. This is, again, down the road, not next year. If the MTBE ban is kept in place on time, this line is going to be impacted. This is assuming a long term, not the 2003, but a 2005, 2006, that refineries will be able to change their systems and make product to come to the West Coast.

Upward import trends. Again, we're talking about barrels can be kept in the Gulf Coast as long as imports backfill into the East Coast. And this trend has shown this. Finished gasoline has basically -- this goes import -- this is showing finished gasoline from the Gulf Coast to PADD 1. And as you can see, it has actually decreased in the last couple of years on the gasoline side. That's because the Colonial's shipping less, and we're seeing more imports into the New York area.

Increasing imports to PADD 1 has allowed Gulf Coast refiners to increase supply to the west and midwest. This is the balancing act we're talking about. If quality is available, this trend is expected to continue as US refineries are at capacity and Jones Act tankers will allow this to keep happening. This trend will change as trade partners increase, and their demands -- what we're trying to say here is we don't know where this is heading in the future. This is a balancing act. This is as world supplies change, as world supplies of clean fuel change, as world demand for clean fuel change, the balancing act which is coming into the United States from other places will change significantly. And it just isn't written yet, if we're looking three years down the road as to how this is going to balance out.

What product is available. Today, no problem on shipping product. We have, Gulf Coast refiners have excess refining. RFG gasoline, tremendous amounts of conventional gasoline. Limited blendstocks, and today, limited California CARB gasoline and/or blendstocks. In the future, it just simply depends upon the price in

California and the demand for blendstocks. Refiners will bring product out here and make it available, given enough time and enough incentive. Three, four years is certainly enough time for refiners to change their systems around and be able to supply whatever part of the United States needs supply.

Specification changes in Arizona and Nevada can change supply. And what I'm trying to say here is both Arizona and Nevada in the future may become more restrictive on their gasoline specifications. The supply/demand we did on the MTBE study assumes that they keep at their current levels of specifications. If they're thrown into an RFG program, or Arizona decides to follow California closely on CARB type specifications, the demand for CARB fuels will, of course, increase, and that will cause a further problem in California supply.

One other thing we found in some of the stakeholder meetings in the last couple of weeks, and we're still trying to evaluate this, but some of the California refiners have mentioned that they need the Arizona and Nevada markets, not just because of price, but it's a quality issue. This is Nevada and Arizona currently in the summer have a lower quality than, of course, CARB material. California refiners may need that outlet for material and gasoline blendstocks in order to balance their system.

The completion of the Longhorn Pipeline to El Paso may cause some refinery capacity to be lost in the region. And not to say that whether -- this is not to say an El Paso refinery or a New Mexico refinery will go down. I have no idea. We're seeing reductions in refinery capacity in the United States. Premcor announced last year they would shut down Wood River. It's already down. They recently announced that Hartford will be going down in six months.

As any refinery shuts down in the United States it affects Gulf Coast supply and demand. And whether a refinery in the New Mexico region shuts down or not, it would be significant, of course, more significant to that region, but it would also affect demand. And it's impossible for me to say at this point who is going to shut down in the future in the United States, but I strongly believe that there would be other closures in the US. There are refiners that have to optimize their system, and make a decision as to whether they're going to spend the capital to desulfurize gasoline in 2005, and desulfurize diesel.

If a local refinery shuts down in the New Mexico region it, of course, will affect the Longhorn Pipeline capacity. That would have to be made up by pipeline product brought from the Gulf Coast.

PRESIDING MEMBER BOYD: Drew.

MR. LAUGHLIN: Yes.

PRESIDING MEMBER BOYD: I'm struggling with some of the facts as they're being presented to us here recently, your comments about refineries shutting down and more thinking about shutting down after doing, you know, cost benefit analyses of whether they want to make capital investments or not. But with the fact that you and others here in the past several weeks have presented information to indicate that demand is seeming to outstrip supply in many kinds of ways, I'm a little puzzled why the business decision is that refining capacity maintenance, if not expansion, is not needed.

MR. LAUGHLIN: To answer that without saying a particular client's name, I've got one client right now who has -- who is evaluating a $100 million expense to be paid in 2004-2005, to desulfurize gasoline and diesel. He can't show his management any return on the investment because he can't prove that the price of his gasoline or diesel will go up at all to give him a return on that investment. Their choice may be to simply run the unit with minimal maintenance until 2005, and then throw in the towel. And that's what I think you saw with Premcor, on their -- certainly they made the evaluation after study to shut down Hartford, and that decision was made only in the last ten days.

There are quite a few smaller inefficient refineries in the midwest that have major capital projects that they'll have to do to survive. And I know it doesn't sound -- it sounds crazy, but their problem is it may be cheaper to import product to the United States than it will be for them to spend capital on their facilities.

PRESIDING MEMBER BOYD: And I was afraid that was the bottom line. So, just like so many other industries who have previously gone that way, so goes this market. But in the face of the discussions of energy security, we still push harder and harder for imports because the world economy can give it to us more cheaply than we can do it here. So we're in a real Catch-22, it appears to me.

MR. LAUGHLIN: Yeah, and in the Hartford case, I assume also the new Centennial Pipeline, which is -- I believe it will be, if it's not online, it's soon to come online, will be able to deliver product in their backyard. And their choice is to spend their money in one of their other refineries, and then use the pipeline as a distribution tool and just concentrate where they'll spend available capital funds.

But the point I'm trying to make is that pipeline was the difference also in their ability to supply their market. So they can simply use the Gulf Coast product and the pipeline to deliver it. A similar situation with the Longhorn line. And I'm not trying to imply that the Longhorn line will force or shut down local refineries. All it does, though, is it makes some of the margins that have been there in the past lower.

And, but there are many other reasons for a refinery to stay up and going, such as a local -- I hate to use the word, too, but the boutique market, and I think we'll find later on that in the El Paso area alone, I understand there's 40 grades, 30, 40 grades a refiner has to make in order to supply his region. And because of that, that may give, and should give refiners a reason to stay around.

But a refiner in the midwest is making your standard conventional gasoline at 300 or 400 ppm, and essentially, in some of these places it is not that they're going from a conventional baseline, which is like 330 ppm sulfur. Some of them have got baselines in place that were extremely high sulfur because they were all established in 1990. And let's assume that a refiner who had an 800 ppm sulfur in 1990 essentially has that today. And if he has to move that from 800 to either 80 or 50, depending upon whether he's small, or whatever, it's a huge investment. And it doesn't -- it may not pay for him to make that investment.

PRESIDING MEMBER BOYD: Thank you.

MR. LAUGHLIN: Arizona and New Mexico demand may utilize Longhorn supply. And again, Arizona is growing at such a tremendous rate that one of the concerns I have is that the line is used just to backfill additional product demand in the region. And I know there are some Longhorn people here today that may address that. It's a good thing for the Longhorn Pipeline, but what it may do is product coming from the east may end up -- what we're hoping is that the product ending up in Phoenix would reduce the demand for California product moving to Arizona.

That might not be the case if Arizona continues to grow at rates that they -- we've seen in the last few years. And again, southwest refinery closures can affect demand on the Longhorn Pipeline.

US refineries can supply product to the Tucson/Phoenix area via pipe. And again, this is just the infrastructure of price competition between not just Texas refineries but Gulf Coast refineries, assuming the Longhorn line will be going. The Longhorn line is, again, expected to be about July, I believe, July, August of this year. It adds more flexibility to the region, it ties in more Gulf Coast product to the region, and then that region, El Paso, is able to then better supply via truck, or hopefully a additional pipeline, to get on to the Tucson/Phoenix area.

And again, there is a pipeline today moving product to Tucson and Phoenix. It's completely full, and I believe there are trucks and will be trucks running instead of just filling up the line, and that's not -- hopefully in the future, somebody will take the line from El Paso beyond to either Tucson or Phoenix.

Pipeline infrastructure in the Houston ship channel area is amazing. Pipelines not just from petrochemical plants to a grid system into different blending facilities, but we have pipelines coming up from Corpus, from Beaumont, tying many eastern refineries together, to terminals, pipelines from Texas City refineries up to the Houston area, pipelines from all the underground storage facilities.

The bottom line is the Longhorn starts in Houston, and Houston has a tremendous amount of infrastructure to move products around to make different grades of product.

Products can be imported from -- to the Longhorn, but again, I don't believe that'll be a direct import. It's just more expedient to import product to the East Coast, backing out Gulf Coast product. If product chooses to come direct, for whatever reason, it can easily be done.

Terminals, Kinder Morgan has two terminals that are fully functioning, gasoline blending terminals. The same with ITC, Oil Tanking and Beaumont. These are mega-terminals with tremendous capabilities.

Initially, the Longhorn's going to move 75,000 barrels, or can move 75,000 barrels. Eventually, it could move as much as 225,000 barrels. Possible regional shutdowns of refineries and local demand could absorb this capacity. It's a problem that we need to study further. Expansion of the pipeline is essential if Longhorn is to achieve this maximum capacity of 225,000 barrels a day. As Longhorn expands, local demand growth will still pull supply from California.

What I believe in the long run is that even if the line is laid all the way to Tucson and Phoenix, for a number of reasons product will probably still get pulled from California to those regions more from a product spec standpoint than anything else. The refineries seem to like that particular area as a home for some of their slightly lower quality product.

The Longhorn will help California, indirectly. And we just talked about the Longhorn needs particular groups of people to push this thing further in order to get it from El Paso, beyond. And again, I use the word Longhorn as a generic. It may not be Longhorn, it may be Kinder Morgan, it may be Williams, it may be a number of parties that complete this line. But it's to California's benefit to see this line is completed.

Gordon will into this later, and there's -- there's stealing a little bit of his thunder when we get into this. But the pipeline study also is studying a direct pipeline directly from the Gulf Coast to California, not an extension to the Longhorn or Orion line, but a direct pipeline.

That direct line could reduce delivery times to resolve problems. And it would tie the West Coast into the US pipeline grid. It would arb the regions to each other. It would create greater supply and price stability. It would utilize the Gulf Coast refining and chemical infrastructure, and reduce West Coast price premiums. It would also reduce, of course, the need for moving product around by tanker, and that would reduce the potential for spills.

Issues that can impact supply. There's a number. There's so many it's just hard to even list them. We'll do both increase and decrease.

Force majeure such as we see in, you know, breakdowns, fires, explosions, things like this. This is changing our supply issues all the time. Environmental regulations, as we've talked about, the ability to possibly shut down refiners in the future because of gasoline and diesel desulfurization. And the Mobile Source Air Toxics rules have also changed and will change some of the refineries' economics.

Legislative changes, as we've talked about, what happens on the national level with MTBE, removal of oxygen standard, renewable fuels.

Again, we've seen numerous problems in the past that each year we get surprised as to what this year's problem will be. But it affects the refineries' ability to deliver product. These supply disruptions are temporary, but they can cause severe spikes.

And we've talked about two refineries, the two Premcor refineries have announced shutdowns due to projected costs of compliance for desulfurization. The Longhorn may cause some regional refinery rationalization.

We're going to see some problems with gasoline octane and volume losses. And again, this comes back to the MTBE issue. Replacing large volumes of MTBE with smaller volumes of ethanol in California does cause an octane problem. Distillates will change some of their features when they go into cracker feed.

Refineries have always been able to tweak capacity, given enough time. And that's an important problem here, is that it's a time factor. Refineries need to understand there's a problem, and then move towards fixing the problem. And in that period of time, with permitting, you might now be talking about two to three years, maybe four years.

Mobile Source Air Toxics. This regulation changed the baseline gasoline for toxic emissions for refiners. What this has done is made blending gasoline in the Gulf Coast a little more difficult. And, in fact, in the East Coast, too. It's reduced the flexibility of refiners and gasoline blenders on their gasoline components. It's actually driven up the demand for alkylates slightly already this year.

The National MTBE ban. Removes significant high octane, as I've said. Reduces volume of low octane. If you remove -- this is a balancing act, again. If you remove high octane material, then you have less low octane material to put in there to make the same fuel, so you have affected your supply.

Oxygen standard stays in place, this could strain ethanol capacity. And what we're saying there is the bottom line is if it stays in place, there's going to be a need for a lot of ethanol.

And converting of butylenes to alkylate or iso-octane helps, but it does not offset the quality volume loss. And this is not -- even in a national MTBE ban, it needs to be understood that the MTBE producers may not switch. They may become foreign suppliers of MTBE, or foreign suppliers of ETBE, or do other things. There's nothing that guarantees a switch to iso-octane or alkylate today. And, in fact, the MTBE producers have said, the on purpose producers have pretty much gone on record and said that the production of iso-octane today is a loser, and they would not make a switch at this point, going from a product -- in fact, I think their real option would be, in some cases, to shut down.

Removal of the oxygen standard. Refiners would tend to use less oxygenates in RFG. For MTBE blended gasoline this would reduce supply, as many refiners would like to use less MTBE. Not having to use ethanol in the summer RFG increases gasoline supply, as increased pentane blending more than offsets the ethanol rejection.

And again, these are issues that are going to have to be resolved in the next few years, but that will dramatically affect the supply and demand of products in the West Coast area.

Renewable fuels standard is another one that is, of course, in vogue right now, that is going to have to be resolved. New ethanol capacity, of course, this is -- that winter grade gasoline won't be a problem. We'll be able to use lots of product and we won't have the RVP problem in the winter that, of course, we have in the summer.

Summer RFG production is down, usually, if ethanol is used. Again, this comes back to backing out higher RVP products, and it assumes that a RVP waiver is not granted. Summer conventional gasoline would go up by the volume of ethanol added, less butane rejected. That may be a net increase in gasoline supply if you were throwing ethanol in some of that material.

Conclusions. The Gulf Coast refiners can increase supply to California -- and I've got to say it's over time, not immediately -- by operating above calendar day rates or by letting imports into the East Coast displace Gulf Coast product.

Imports are available and can help California supply either by direct shipments to California, or displacement from the US Gulf Coast. And again, we're looking at 2005. This is assuming that refiners are able to make changes and bring product in. They are limited, there are limited availabilities 2003 and 2004. Refiners worldwide are able to cherry pick their best products and send them into California, but it's still very limited.

The Texas to California pipeline capacity will help supply and lower California fuel costs. And supply, other quality supply issues come into play when we talk about CARB blendstocks, and I can't stress enough there is a tremendous difference between RFG, conventional gas, and CARB material.

Task 3 was to evaluate the marine products tanker fundamentals and moving product from the Gulf Coast to the West Coast. We're going to review basically historic product tanker movements, product tanker economics, and domestic product tanker outlook.

The logistics of moving product to California via the Panama Canal, we're going to take a look at the vessel trip time to California. Again, historical movements, and California receiving facilities.

The logistics of moving a cargo from the Gulf Coast to Panama. Of course, the cargo's got to be accumulated, which is significant here because I want to go back a second, let's talk about alkylate. Very few refiners sit on a cargo lot size of alkylate. It needs to be loaded, usually in two or three places. So if we were just talking conventional gasoline, no problem. They usually sit on cargo lot size of conventional gasoline. When we're talking about alkylate, it usually has to find two or three loading places to load 75,000 barrels here, 50 there, and then fill up a whole cargo.

Then, of course, sail to Panama, wait for a slot in the canal, which today is very minimal. Traverse the canal, sail from the canal up to LA or San Francisco, and unload.

Activity time. This is just running through this quickly. But I'll show you why it impacts California in a few minutes. But we're just talking hours here to berth the load and to de-berth. The activity to -- the time, 120 hours to the canal. Waiting time, this was averaged over the years as about two days. When we did this, started this report in September, it was actually seven and eight days, and after 9/11 it really got out of control, at least temporarily, while they made sure that ships were not going to damage the canal or be blown up in terrorist acts. So the canal is always a wild card as to how long it takes to get through, but it has been much better in the last few months.

And again, then you have time to traverse the canal from LA -- or to LA or San Francisco. This chart's time is pretty standard, but to get down to the bottom, it takes a total voyage time is about -- let's use San Francisco, about 22 and a half days, rounded off to 22 days, to make a one-way voyage from the Gulf Coast to the West Coast.

Again, this is time required, in summary.

Why don't we start here. Six ships. And the reason I picked six ships is that's about 37,500 barrels a day that six ships could supply to California. Six ships is probably getting close to the outer limits as to what might be available in 2003 and 2004. 37,500 barrels gets to be the upper limit of what might be available from the supply standpoint. There might be 40,000 barrels or 50,000 barrels of product supply in the Gulf Coast. At some point you're either going to be product supply limited, or you're going to be ship limited. And that's why I say that, as we talked about the -- go back to the MTBE problem, that a MTBE ban causing a shortage of 50,000 barrels a day could probably be supplied by both foreign and domestic sources. Exceeding that, we start to come into problems.

Historical movements. We'll go through

some charts showing movements from PADD to PADD, and the significance of this is, again, to show how product is moving around today, because you have to understand what demands are put on the Jones Act flagships today to understand why they can't just easily be pulled off and taken to a California trip.

This is PADD 1 to other US via water. You see there's very little movements, but there is some significant movements back to PADD 3. And the significance is this. PADD 1 has naphtha and unfinished blendstocks that have to move back to the Gulf Coats, there's no other way to move them but by ship. Those ships can't be replaced. Those movements have to take place.

PADD 1 to PADD 3, what's moving. Gasoline components, basically you see the green line at the end is basically unfinished and others. It's naphtha and cat feed for the most part. It just exceeds, they're producing more feedstock on the East Coast than they have a capacity normally to consume.

PADD 3 to others via water. The green is the lower Atlantic, and, again, this is Florida, Georgia. Here you see the Gulf Coast supplies tremendous amounts of product to Florida and Georgia. There is no other way to do it. The only other way to do it would be to bring in imports directly into these states.

PADD 3 to PADD 1 via water. Again, this just shows what's moving. Essentially, it's gasoline with some jet and distillate moving up to the East Coast.

Florida and southeast product demand. This is the point that I have to stress, that the terminals in the southeast are not well equipped to handle full cargo lots of a single grade of product. They weren't built to be able to buy product directly from Europe. This is important. You can bring in cargoes, let's say, from Europe into a southeast terminal, but most of them aren't designed to handle 300,000 barrels of a single grade. So that ship may have to call on a number of ports to discharge across Georgia and Florida in order to get rid of its product.

US vessels, when they load off the Gulf Coast, will either load a single product and go to a number of terminals, or, most likely, haul multiple grades of product to a single terminal. So a Gulf Coast ship may load jet, diesel, three or four grades of gasoline, and discharge it at a single terminal in Jacksonville, and then return for another trip.

The lack of US quality clean fuels from foreign sources inhibits the replacement of southeast Florida production from foreign suppliers. And what I'm trying to say is that, for instance, let's go back to -- let's use Venezuela. Actually, they make a better product. They make an RFG. They don't want to go to Florida. It's a conventional market. They don't want to take their product into Florida and then discharge it all over Florida. They would rather take a single ship into New York Harbor and discharge it there for a higher net back.

Product coming out of Europe may be slightly off spec and needs to be re-blended. There's very few blending facilities. There's only one, actually, in Florida, and it's a very small one, that can re-blend offshore gasoline to make American specs.

And again, products meeting US specifications are not readily available to southeast terminals from foreign sources. And, again, clean products must be shipped from the

Gulf Coast. We can't cut that off. That needs to happen. And this is why these ships have to continue to go to the East Coast and are not easily reassigned to West Coast service.

PADD 3 to PADD 5. Years past, you can see this problem here is in '96-'97, how it spiked up. That level is going to have to be exceeded, actually, in an MTBE ban. We're going to have to, instead of having a peak, we're basically going to have that as the norm.

PADD 3 to PADD 5, I want to go over. This is the typical time it takes for a ship to go Jacksonville, and I'll show you why it's significant in a minute. Eleven days, basically. But again we go back, let's go back to San Francisco and say it was 22 days, or a round-trip takes 44 days. So that same ship could've made four movements to Florida instead of one movement to California. Obviously, the ship owner wants a lot more money for that.

But the point I want to bring out, it isn't just a shipping problem. That ship theoretically would have moved 1.1 million barrels to the East Coast. Somebody has to make up that volume. And that volume, again, if all the ships are tied up, would have to come from offshore sources. Well, offshore sources don't have the particular quality that might go directly into the southeast. This upsets the balancing system we've been talking about.

California receiving facilities. A great deal has been said yesterday and in the MTBE report as to the limited facilities out here to handle waterborne products. Existing facilities are refinery owned, or mostly refinery owned, a small number of independent storage facilities in California. And non-California sources reluctant to speculate on their ability to bring cargoes out here.

This is just a fact of life, not a criticism. This is the way it is. World sources are reluctant to come here because they can't control their destiny. They have to deal with California refiners for good, bad, or indifferent. It's just the way the system is. It reduces the ability of the world market to supply California.

Product tanker economics. Again, let's talk about the world supply. Let's bring product from Rotterdam, or Sicily, or Singapore. These are just typical places. But what we've done is we've increased the amount of time it takes to supply product into California from other sources in the world. Also, and this is an important point, very few sources in the world have alkylate sitting in any quantity at all.

Now, refiners and traders worldwide will be looking, assuming an MTBE ban comes in place, they will be looking in the worldwide system to see what they can break out. But it's -- the volumes are small, and they would have to be accumulated. And then there probably won't be enough to fill out a ship, so they would then have to also be added to other volumes coming from other foreign destinations.

The problem with that is in putting together a cargo, it takes more time. And that means the supply time to re-supply California has just extended from 20 days to maybe 40, 50 days. So the total, let's assume it takes about 15 days over voyage times, so we're saying that now from foreign sources, we're now maybe 35 to 50 days to arrive a cargo on the West Coast.

The domestic product tanker outlook. There's very few tankers under construction. The OPA 90 is going to require all single hull tankers to retire by 2015. We'll go into new tanker economics, and we'll also talk a little bit about what happens when an MTBE ban.

The Jones Act vessel inventory on a separate sheet, or at least in the report there's data on the ships. Several of these vessels on the West Coast you'll notice already, most of them actually, are single hull already, and will have to retire.

The current US fleet, total fleet, is 106 ships. That's clean and dirty. Sixty-six are product carriers, 40 are crude carriers.

New ship construction. We've been told, although I don't believe the contracts are actually signed, that there's two new ships that are planned. I don't think that's -- we're still not sure that's actually going to happen. These ships are not planned to be in the Gulf Coast or California trade use.

There's only three shipyards that re capable of making tankers in the US now. Obviously, the business hasn't been there, so the amount of shipyards that are available to make product has diminished.

OPA 90 retirement schedules. Ninetythree of our 106 tankers are going to go away. Thirteen vessels are exempt because they're already double hull. Forty have to retire by 2005; 31 by '10; 22 by 2015.

That's the product shortfall. This chart is a little unfair in that it has both crude and product tankers in there. There's another chart that shows a more gradual decline, but a serious decline if you're just looking at product tankers. But in 2005, we still are going to retire a great deal of product tankers, making shipping product to California in 2005 and beyond a real problem.

So that brings up the question, why don't we build them. Why don't we build ships. If we need them, we should build them. The problem is this. It takes $40 to $45,000 a day/lease rate to justify a new ship today for 20 years. And you would want a contract to do that in order to build ships. Lead time is about three years. And the current rates -- and, in fact, these are even lower now -- are $35,000 a day. That's well below the rate to guarantee the profitability of building a ship over a long period of time.

Potential pipelines, just the talk of extending the Longhorn Pipeline to the West Coast, or the talk of converting a gas line from Houston to Florida, has to scare any US Jones Act ship manufacturer or ship owner into a wait and see attitude. You certainly wouldn't want to build a ship and then have a pipeline come in place to take your movements out from under you, and then you're sitting with an expensive ship and a deflated market.

As I said, the construction of either of these pipelines would idle existing ships, so ship owners and ship builders are in a wait and see attitude.

Blue water barge construction. This may be how the industry goes in the future. New construction of these larger barges, these are 250,000 barrel barges, may be a viable alternative. They are much faster than the current barges that make only 11 to 12 knots, and the construction cost is considerably lower than a new US vessel. But we're still talking probably $50 million.

Current blue water barges, why don't they work. And this is a trading problem, I'll show you. Blue water barges only transport about 150,000 barrels in a barge today, at a slow 10 to 12 knots. Typical US flagships transport more product at a greater speed. The importance of -- from a trader, or even a refiner shipping product quickly to California, comes into play in that we're talking about the forward market again. And we talked extensively yesterday about a forward market.

If a ship can get out here in 20 days and a barge gets in here in 30 days, the first guy here usually gets the higher price. It's not just that the barge would cost more on a per barrel basis, but it gets here later. And to a trading company, refining, trader, however you want to look at it, speed is really important in order to capture the higher prices in the prompt market. So basically, barges don't leave the Gulf Coast, blue water barges don't leave the Gulf Coast for this trade.

Ship demand. We talked about the ship demand for moving VGO and naphtha from the East Coast to the Gulf Coast. This has to continue. One of the things that happens, though, is the ship owners have gotten real creative on the ability to move back and forth between clean and dirty. What they'll do is they'll move a dirty VGO down to the Gulf Coast and then clean, and then take a finished product back to the East Coast. The significance is that cleaning takes time. They're willing to do that because they've got backhauls both ways.

What this does is it might take a ship that would have made three hauls, and he can only make two hauls. But it is a -- it works for the ship owner, and that means he'll do it. The Florida and East Coast markets are going to have to be served. Unless there is a pipeline in the future, which is a possibility, but nothing is planned at this point.

Ships also, we've seen, could fill the void when barges are used to go upriver. This happened recently with Chicago problems. We had quite a few inland brown water barges that moved from the Gulf Coast up the Mississippi to Chicago. Those barges were moving product around, for instance, between Corpus and New Orleans, and instead the ships came in and filled the void. We lost a few ships. Of course, that's the whole point of the Jones Act, is to have ships when the military needs them. And if the military needs the ship, they get it. And that has happened here recently.

Seasonal high demand for clean products in the East coast can affect, and this is, again, the speed of a ship moving product from Houston to Boston, for say, and with diesel or tolu, might be able to take advantage of a very high price market, or a price spike, or a very cold winter. And all of a sudden we have tremendous demand on ships.

Jones Act waivers. People have talked about this time and time again. They're very rare. And they occur only in short, short terms. Extended terms not likely. The support for the Jones Act comes from so many different groups, so many different areas. Refiners, unions, ship builders, other ship owners, have been able to successfully claim it's unfair to them to have a ship at a very expensive rate, and then have a waiver come along and seriously affect their markets. And the ability to do a long-term Jones Act waiver, it's never been sustained.

Will MTBE phase-out make more vessels available. The answer is absolutely no. There are four vessels today in the US fleet that are MTBE/ethanol only. Believe it or not, once a ship is retired from its OPA 90 classification it can haul MTBE or ethanol, but it can't haul products anymore. Four of these ships are hauling MTBE or ethanol. They're already too old to haul gasoline. Therefore, when MTBE is banned they may haul ethanol, but they cannot haul finished products.

Most of these other vessels in service today, as we said, have dedicated services. They make pretty consistent runs. They go from whatever refiner to their markets all over the US, and pretty hard to pull them away on any sustained basis.

Another point on the West Coast, we discovered that there are quite a few refiners that have made sure that they don't want older ships at their dock. Whether, you know, this is an environmental issue, a safety issue for them, what it does, it reduces the amount of ships available that can make the trade out here.

Meeting California's needs with no foreign supply, and meeting California's needs with both domestic and foreign supply, we're going to take a look at.

No foreign supply. If California is short 100,000 barrels a day after an MTBE ban, the average total time is 44 days to San Francisco, and, of course, it'd be lower to LA, average ship of 275,000 barrels, it would require 16 ships to do this. It isn't doable. That's not a maybe, it isn't doable. We cannot take 16 ships out of the available 60 or so clean American vessels, and put them on a long-term constant California movement. And this is, of course, the worst case scenario, there would be no foreign product. That's, of course, a ridiculous statement. There will be foreign product.

But the point I'm trying to make is you cannot pull 16 vessels off their current movements and make this happen. And that's in 2003. Remember, between now and 2005, we're going to lose 10, 12 more vessels. This becomes an absolute, there's no question. It can't be done in the future.

Foreign supply. Foreign flag vessels are easily available. There are many of them, and most of them, quite a few of them are double hulled. Vessels available, and quality supply has been found in the past in Canada, Caribbean, Europe. But the supply is limited. Producing California gasoline also could dramatically reduce RFG production for other US markets. What I'm trying to say here is that right now, this particular Canadian refinery is making RFG for the harbor. If he chooses to make CARB for California, it affects his market, or his supplying the markets of RFG to New York. Somebody has to make that up. It's not a -- the system goes out of balance.

Again, if we go back to foreign supply, delivery time would be increased. The time required to resolve supply problems would increase. The term and the magnitude of a price spike may increase just because of the time it took to solve the problem. We saw that many of the price spikes in the past were of a limited duration, five and six weeks, basically the time it takes to get product moving out from the Gulf Coast. That can mean that the probability is that future price spikes might be longer in duration. And again, the foreign supply gasoline, the vessels are there, but the product may not be.

Again, conclusions. OPA 90 retirements

will create significant tanker shortages. Movements between the Gulf Coast and the South Atlantic have to continue. Current tanker rates don't justify new construction. And California must rely on some foreign supply in order to fill the void for future demand out here.

And with that, I'll turn it over to Gordon, wherever he may be.

MR. SCHREMP: Yeah. Thank you, Drew. My name is Gordon Schremp, I'm a Senior Fuels Specialist on Staff at the Energy Commission. I work in the Fuels Office.

Before I get going on my presentation, which will include a summary of the work performed by Interliance, I'd like to introduce a couple of additional individuals, and that would be Jill Episcopio and Walt Ford, from Interliance. They're sitting at the table, and they are the consultants that did the lion's share of the work for this -- their report, that you find out in the front desk, in the foyer.

And I'd also like to point out Ramesh Ganeriwal, who has been working tirelessly, along with ourselves and the consultants, for several months now, working on these different reports.

So I'd like to thank them for all their hard work.

All right. Without further ado, I'll proceed with my presentation.

A little background on basically why we're here today. Assemblywoman Migden's bill, AB 2098, was the, I guess the impetus for us to perform this analysis. Like I said, the lion's share of the work was performed by Interliance. We also contracted with Drew Laughlin, who just presented his findings in his two areas of expertise.

There are the three studies. We have them -- we will have them all available in written format today for you, hopefully by noon, and on the Internet today, as well, along with our Power Point presentations.

I'll go a little bit on the overview of the -- for the people, and I've skipped a couple of slides. I'm on Slide 4 now, for those listening on the Internet.

I'll cover some of the fundamentals about pipelines. And certainly, if you're going to convey petroleum products from a point of supply to a point of demand, you can use a marine vessel, you can use a tanker truck, railcar. But pipelines are by far the most economical means, and also a very means of moving product.

New pipeline costs vary, about $1.5 million per line mile on some of the more recent projects. As you see, a breakdown of the various components, mostly labor, and we have engineering and construction are the next biggest, and land acquisition or right-of-way acquisition is about ten percent, on average.

They usually require a payback period of about 10 to 20 years. Certainly pipelines have a longer useful life. Many of the pipelines in California and other places in the United States are in excess of 40 years in age. And the revenues that are generated by these pipeline tariffs are basically the sole means of money for these projects.

There are several pipelines located throughout California and what we call the southwest, which is a region of California, Nevada, Arizona, New Mexico, and Western Texas. And we have I think an expanded picture of one of the graphics that is in the Interliance report, that does show the interconnection of the pipelines, and we have it up in the easel in front of us.

Kinder Morgan is -- well, first of all, we'll talk about California. The majority of the petroleum products in California that are produced in the refineries are dispensed through a network of pipelines to 60 terminals located all throughout the state, all the way to Chico, and down to Imperial. And we have pipelines connecting ourselves to places in Reno, Las Vegas, and the Phoenix/Tucson marketing area.

The common carrier pipeline is Kinder Morgan. And there are several other proprietary pipeline operators, and these are the majors, such as Chevron, BP, et cetera.

A little bit of additional detail on our shipments to Nevada. Certainly the lion's share of the products going to Reno and Las Vegas come from pipelines originating in California. The Bay Area refinery complex serves as a source of petroleum products for the Reno market, about 36,000 barrels per day of all products, and these are -- these figures are from 2000, average for the year.

And Las Vegas, there's certainly a lot

more, a much larger metropolitan area, much higher demand, almost 110,000 barrels per day. And once again, almost all of the product does come from pipelines originating in southern California and the Bay Area. There is some shipment by tanker truck out of the Salt Lake City area, at times.

Arizona, this is another location that does not have their own refineries, and depend almost solely on pipeline delivery for all their petroleum product needs.

As you can see, the majority of the petroleum products do originate in California, and the rest are shipped from the east, what is called the East Line, originating in El Paso, Texas, which is in the very far west, western area, the western Texas panhandle.

The Phoenix/Tucson from California, and the reason there's a slash there, there's actually pipelines connecting Phoenix and Tucson that allow product to move on one line from Phoenix to Tucson, and from Tucson back to Phoenix. Shipments from the west in 2000 were about 126,000 barrels per day, most of that gasoline, and then from the eastern side, about 87,000 barrels per day average. And during the peak periods of demand, that pipeline is full. And we'll talk about the significance of that. The west line capacity is not full at this time.

There's been a discussion already about the Longhorn Pipeline originating in the Houston complex, and terminating in El Paso, which is the point of origin of the east line for Kinder Morgan. We do expect this pipeline to become operational sometime in the second or third quarter of this year. Line filled by the end of the second quarter, and third quarter shipments of products.

Initially, between 70 and 75,000 barrels per day of petroleum products will be anticipated to be coming on this line into El Paso. An upper end capacity in the design, which would require the addition of pump stations, is about 225,000 barrels per day. So this is rather a significant addition of delivery capacity.

The project was initiated in 1994, and what's important to point out is we are finding ourselves in 2002, which is eight years after the point of initiation, so you can see it can take a significant period of time to get these projects from point of initiation to completion.

And these are primarily caused by lawsuits, and there was mitigation work undertaken by Longhorn to address environmental concerns, primarily with regard to the Edwards aquifer in the Austin region.

Back to my comment on the deliveries from El Paso to the Phoenix/Tucson market. That line is essentially full. Demand in Arizona, like California, is increasing a little bit faster rate than our projection for California, at one point six percent per year. But what this means is that all future demand in this region must be met from supplies originating in California. It doesn't necessarily mean that is from California refineries located in southern California, there can be some importation. But what we do see today is most of that product does come from California refineries.

And as I mentioned earlier, the west line does have spare capacity at this time to handle additional imports over the near term. And that's the next five to eight years. But as you certainly move farther out, and if the demand projections are a little bit higher, that line, too, will reach a point where it will become full and become pro rated.

New pipeline. That's what the study was basically about, the feasibility of constructing a new pipeline between Houston and California. Interliance did this work, and I think it's important to note that like many of these initial studies, these are conceptual studies. These are not detailed engineering studies which would further quantify these costs. And it's possible that these costs could be a little bit higher or a little bit lower, as a result of more detailed engineering analysis.

But the basics are they looked at two different pipelines, because there are two different capacities. And the smaller line, 12 inch, about $800 million; and 24 inch about double that, $1.6 billion. And those costs are spread out among the other previous breakdown I showed you, you know, labor, materials, procurement, rights-of-way, et cetera.

Timing, four years. That may be, in light of the Longhorn experience, a little bit optimistic in terms of the permitting time period of 18 months, with material procurement.

Capacity, as you can see, it's almost

triple on a 24 inch line at about 150,000 barrels per day, upper end capacity, and 50,000, if it's a 12 inch line.

If a pipeline was constructed, or if one were considering constructing a pipeline between Point A and B, you could operate that pipeline in a couple of different modes, or what we call operational options.

One is essentially the pipeline would be a real long tube for a Strategic Fuel Reserve, four million barrels of line fill, and one could then draw upon that if there was an unplanned outage. That is a 24 inch line. The second operational option of a feed source to fill up that Strategic Fuel Reserve is a 12 inch line. So it's a little bit of apples and oranges there.

And then, obviously, the traditional means of using a pipeline, and that is just to deliver product from a point of supply to a point of demand.

So now we'll take a look at what are some of the issues associated with these three different operational parameters.

We'll look at a Strategic Fuel Reserve. Certainly if the product is sitting in the pipeline and not moving, which is abnormal, that's intermittent operation, and there are problems. There's shelf life problems we call interface problems, and if you had multiple grades, say you wanted to ship blendstocks and then finished gasoline, well, at some point those liquids are up against one another and usually, in pipeline operations, when you have movement, the liquids are pumping against one another and there is some intermixing. But if it just sits idle, you'll have a lot more. So that's a problem for quality control.

And, once again, if the pipeline is not in operation and pumping, you can't tell if there is a pressure drop which allows one to determine there is a possibility of a leak and then to also isolate where the leak might be. If the pipeline sits idle, much more difficult to detect and locate a leak, if there was one.

Certainly on a cost basis, looking at that 24 inch line, $1.6 billion to probably an upper end cost of $100 million for a Strategic Fuel Reserve that would be, say, a series of tanks located in northern and southern California. And these cost figures do not include the amount of money it would take to purchase the product to fill both those reserves. But that cost would be identical, if we're talking about the same volume.

Certainly a lot less flexible, if you use -- try to use the pipeline as a Strategic Fuel Reserve, you have only one location where that pipeline has an outlet, versus multiple locations if you have tanks for an SFR. And the same when you're trying to re-supply your Strategic Fuel Reserve, when you have a single point of re-supply that's the point of origin of the pipeline, versus multiple re-supply options, foreign supplies, other locations, to refill the tanks, if they were in California.

So our conclusion, and I think those of the contractor, as well, is that the pipeline should not be constructed to operate as a Strategic Fuel Reserve. Impractical, and costly.

A second operational parameter. Filling a Strategic Fuel Reserve, you have the same intermittent operations because it may not be operating constantly, although it would be more frequency than an SFR configuration. But once again, much more costly. $800 million to create the pipeline, and I have versus $17 to $42 million.

You ask, well, for what? Well, that's basically to transport the product on those domestic ships that Drew was talking about from the Gulf Coast to California. And that's the cost to transport about four million barrels in the cost range of 10 to 25 cents per gallon. And therefore, the pipeline should also not be constructed to operate as a source of product to fill a Strategic Fuel Reserve.

So we'll get in a third, traditional operation of a pipeline. There are three main factors to consider, and Drew Laughlin touched on two of these this morning already. You certainly have to have demand, an increase in demand that is not going to be fulfilled from in-state capacity increases, from the refiners. So, in other words, you expect to be importing a sizeable amount of additional product.

Well, then you have to have adequate supply at the other end of the pipeline, the point of origin. And then the anticipated tariff of such a new pipeline would have to be less than alternative transportation mode, which would be, the next most efficient mode would be marine vessel. I think Drew spoke to those last two bullets at length this morning.

Let's talk about demand. Everyone knows California demand continues to increase. The base case projection by the Energy Commission is about 1.6 percent per year. We do expect to see a decline in refinery capacity in California of about five percent, and that's primarily the result of removing MTBE from use in commerce.

Therefore, what happens with the combination of a drop in production and a continued increase in demand, we expect additional imports of gasoline and/or blending components to range from 56 to 100,000 barrels per day.

Therefore, based on this information, it would seem that there would be sufficient additional demand in California for imports that can justify the construction of a pipeline between Texas and California, and the big if, in capital letters, not a typo, is an adequate supply from that location of the Gulf Coast.

These are essentially the highlights that Drew covered in extensive detail. Just want to touch on the main ones again.

Certainly few refineries can make CARB

gasoline, and alkylate surpluses is questionable, especially of the quality that the refineries in California would need, and this is primarily distillation properties. And we do believe that gasoline supplies will be available from other locations around the world. And the marine costs for those vessels is a lot less than that of domestic carriers.

So the bottom line and the conclusion here is that adequate supplies of sufficient quality do not, are not available to merit the construction of a pipeline between Texas and California at this time.

Marine shipping. Once again, just a summary. I think Drew had 66 product tankers, and I believe two went out this year, so I think this is basically a 2004 number. And in Drew's slides he had a combination of crude and product, and so what you have, when Drew mentioned a gradual, more gradual decline of the product tankers, yes. But still, 18 additional ships are coming out of service between now and 2006, which is very significant, especially in light of demand increasing throughout that whole period.

And Drew already went through the

calculations, 100,000 barrel a day in 16 ships, MTBE phase-out will not free up. And the shipping rates, which have a pretty broad range but go up to a very high level, we expect these rates to increase over the near term because of constant increasing demand and declining capacity of these vessels.

Therefore, it's reasonable to assume that a tariff structure created for this pipeline could be less than that of these domestic Jones Act shipping rates from the US Gulf Coast to California. And we don't have a tariff calculation for the pipeline.

Essentially, tariffs can be constructed under different scenarios. One is a market based approach, whereby shippers agree to pay a specific per barrel price between Point A and Point B. Another way of constructing a tariff is to do a cost based analysis, and that has -- depends on how much you invested, what your anticipated rate of return is, et cetera.

So we have not performed this analysis, and neither has Interliance. It wasn't part of the charge, and certainly would have been the next step in the analysis if we thought a pipeline between Gulf Coast and California would merit further scrutiny.

There are other ways of looking at the whole southwest pipeline system that can create additional supplies for California, at least the opportunity of additional supply. And we refer to that as indirect supply. As I mentioned before, the east line being full, this portion of the Staff report does look at an expansion of that east line capacity.

And there are some other factors that one must consider when assessing that expansion, and how much indirect supply it can create for California, at least the possibility thereof. And that is, what's going to happen to the refinery capacity in that region, in El Paso, what's going to happen to Arizona gasoline specifications. As well as regional demand in the western Texas panhandle. And then we'll touch briefly on a new Las Vegas pipeline between Phoenix and Las Vegas. The only pipeline now into Las Vegas is from southern California.

East line. These are the basics. It is full. Additional demand we anticipate being supplied solely from the west, without expansion of this east line. And Longhorn Pipeline, we do assume it will be operational sometime this summer, 75,000 barrels of additional supply capacity coming into the El Paso region could in part be available for an expansion.

And therefore, that would provide the potential, and underline that word, not on the slide, but, of additional supply going into the Phoenix/Tucson markets from the eats, and the option for refiners in California to reduce shipments from the west.

And this can create the ability to increase CARB gasoline production in California, because many of the components that a refiner does use to blend to make an Arizona specification are similar and can be used also to produce CARB reformulated gasoline.

Refinery capacity in the region. Six refineries in western Texas and New Mexico. The refineries in western Texas are of larger capacity and complexity, on average, than those in New Mexico. These refineries currently provide the lion's share of products to this region.

There is an expectation that once the Longhorn Pipeline becomes operational, that some of this refinery capacity will decline. And we also anticipate further refinery decline as a possibility, once lower sulfur regulations are instituted in the US in 2004/2005, as well as lower sulfur regulations in diesel fuel in 2006 and 2007.

So what does happen if there is a refinery production capacity decline is some of those Longhorn barrels will be needed to satiate that loss in local production. But that analysis, a rather in depth analysis has not been performed by the work that Interliance did, nor the work of the Staff at this point in time.

Arizona specifications. Right now, shippers into the Arizona market have two options. They can send a gasoline that's close to a federal reformulated gasoline specification, or gasoline that's close to a CARB reformulated gasoline specification. And I say close because the specifications are similar, but not exactly the same.

And one difference is the requirement for ethanol at ten percent by volume in the winter months, and using essentially a CARBOB 2 look-alike gasoline. MTBE in Arizona is scheduled to be phased out six months after California ultimately phases out MTBE. And this loss of MTBE will decrease supply capability, meaning that in the summer months, the majority of the gasoline going into Arizona does contain MTBE, about 11 percent, by volume. So this supply would have to be made up.

So adoption of a more stringent gasoline specification -- well, that's -- so this is another issue that's being looked at possibly by Arizona. If Arizona adopted CARB-like specifications only, that would require basically identical blendstocks that California will be looking for, and this will be Phase III RFG, if Arizona were to do something like that. I'm not saying they are. And that would increase the demand for those scarce components that California would want into the Arizona market, as well. So that would, I think, probably decrease the number of potential suppliers to that market at that future time, if Arizona were to do something like this.

Demand in that region is also increasing, a little bit more than California. And therefore, that demand, we expect some of the

Longhorn shipments to help meet that growing demand in the west Texas and New Mexico regions.

I'll talk a little bit about the Las Vegas, a new pipeline. Right now, Las Vegas receives almost all of its product from southern California refiners, via a pipeline that goes through Colton and Barstow, then up into Las Vegas, as well as all the jet fuel from McClaren Airport.

Now, additional demand over this period of time is expected to be only from southern California. This is the same story that we had for Phoenix/Tucson market. And the California -- the gasoline specifications are less stringent in Las Vegas at this time. There is also some discussion of making those specifications more stringent. And I think an important point to make here that hasn't been raised yet, and that is that refineries in California are able to utilize all of their blendstocks most economically by marketing gasoline not only in California, but also gasoline in Las Vegas and Phoenix.

What that means is there may be some components that are a little bit higher in sulfur, as an example, that are difficult to fit into

California gasoline, but make a perfect fit for a blend that goes to Las Vegas. And I'm not saying Las Vegas gasoline is dirty by any stretch of the imagination. It's quite clean, compared to a lot of other conventional gasoline in the United States, as well as other locations in the world.

But once again, a refiner must be able to balance how its entire system of everything that's being produced at the refinery has to be able to find a market. So if the gasoline specifications become cleaned up in both Arizona and Las Vegas, that could create some other issues.

I think the last -- I think there are four slides here, I'm on Slide number 24. These are the Staff recommendations, certainly not the recommendations of the Energy Commission at this point in time.

And Staff is recommending that the Commission support completion of the Longhorn Pipeline. And I know I told you we expect the pipeline to become operational later this year, but in case something does come up that creates a delay, we would support its completion and operation.

We also recommend the Energy Commission support expansion of the east line between El Paso and the Phoenix/Tucson markets, as a way of providing indirect supply for California, as well as construction of a new product pipeline to Las Vegas from the Phoenix/Tucson region.

There are a couple of areas that should have some additional analysis, and that is that whole supply/demand balance and refinery rationalization, is one word that people do use, of what may close, what the impacts of refinery capacity clients in that region have on potential supply availability for California.

Also, a further analysis on changing the Arizona specifications, and also further, what's not on this slide, is an analysis of what does happen when Arizona phases out MTBE six months after California, what gasoline is expected to come into that region at that time, because it certainly will not contain MTBE, which is the case during the summer months today.

The Staff is concluding, I think along with -- I won't speak for Interliance, but Staff is concluding that a pipeline should not be constructed. It doesn't make sense because primarily inadequate supply at the point of -- the source point. There should not be any investment by California for such a project. And we think that the El Paso expansions are going to happen by themselves, natural market forces, because of the pro ration of the line, and at some point, the west line becoming full because of increased demand.

This recommendation, for what we call, I think, streamlining of the review, the permit process, the approval process, is I think primarily a result of what has happened with the Longhorn project taking an unnecessarily long period of time. And this does create many problems for potential investors to get agreement to move forward on projects because of these lengthy delays, and how the market can change significantly over a period of this time.

So I think there might be some ways of working together, and certainly California does not dictate what these other entities do, but there may be some ways that they can get together and streamline their process, I think that something analogous that's been done in California.

And that concludes my presentation from the Staff point of view, and I turn the mic back over to Commissioner Boyd.

PRESIDING MEMBER BOYD: Thank you, Gordon, and thank you to all the presenters.

I think what I'm going to ask now is rather than take -- immediately move to lunch, I'm going to ask a show of hands of how many people in the audience intend or desire to make some comments, or have a presentation, and that will dictate to me whether we should just keep going until we finish, rather than break and come back, or whether there's going to be sufficient number of people to warrant a break and coming back.

So could I just have a show of hands of -- and err on the side of who wants to make presentations? Three hands. Going once, going twice.

Well, in that case, I think I would prefer to just press on and let us finish this, rather than interrupt and have to come back and what have you.

So I'm going to throw the floor open, the microphone open to stakeholders and the audience to just come forward to the podium and ask your questions or make presentations and start a dialogue between Staff, contractors, and you folks.

So please have at it. Just identify yourself and your association when you come to the podium.

MR. HOBBS: Is this on? I'm Horace Hobbs, from Longhorn Pipeline.

PRESIDING MEMBER BOYD: Ow. A lot's been put on your shoulders today.

MR. HOBBS: Yeah. We're going to -- we're here to save California, and happy to do so.

The -- first of all, I want to thank you all. You all have already been a supporter of Longhorn, and perhaps you know it, perhaps not. When we were having a very, very difficult time getting some of our permits during our environmental assessment, the Energy Commission wrote a very helpful letter to the EPA on our behalf, and we think we owe some of our success today to that letter. And so thank you very much.

We're in a unique position. You all probably understand that California has always been the key driving force for us. We did not initiate Longhorn to send barrels of gasoline to

El Paso. There's just not enough demand there. And for us, five, six, seven years ago, we began to see a change in the future supply patterns, because of the inability to expand refineries here, the high rates of growth in the southwest, and the ability of the US Gulf Coast refiners to make these specialty fuels. And so our sights have always been set on California, and California is the reason we are in business and have pressed on so hard over the last five years of delay.

I want to add a little bit, we've learned a great deal during the last five years. And so I would like to share some of those learnings with you all, as you all deliberate this, and other aspects from these workshops over the last couple of weeks.

One of the comments was that building a pipeline is a low risk investment, and so there would be plenty of people willing to make that and finance it. And I'm here to tell you that's not right. And in fact, from here on out, we expect, because of our experience and because of experience on a couple of other pipeline projects, that the availability of people willing to take the risk of a huge many hundreds of million dollar investment in a stagnant piece of pipe, they're getting to be fewer and fewer.

You all are going to be the beneficiary in many ways of your investment in Longhorn. One of our significant cash investors is the Beacon Energy Investment Fund, and their largest investor is CalPers. So you already own a piece of Longhorn. I wanted to pass that on to you. Hopefully we'll make -- that'll turn out to be a good investment for them.

PRESIDING MEMBER BOYD: I wasn't going to draw any analogies to Enron, but --

(Laughter.)

MR. HOBBS: We've got to be able to do better than that one.

We're a little more bullish on Gulf Coast supply of CARB gasoline than are your consultants. And we have to be, because, as I say, California is what we're about. And it's mentioned several times that there are only a few refineries in the Houston area that can make this stuff. And while that's true, those few refineries are 400,000 barrel a day each size refineries. They're not 100,000 barrel a day refineries like you have in many of the ones in

California.

And while many of them do not regularly make the things, the kinds of blends today, they have told us and assured us that they will be able to make them. And so we're not, we don't assume that we will have hundreds of thousands of barrels a day of CARB gasoline available for Arizona next week or next year, but over time we feel confident that we can eventually supply the entire Phoenix gasoline demand. That's what the size of our line is based on, and it's based on eventually California being out of supply in Phoenix.

And some of the extension projects that we've thought about, we've thought about Las Vegas. That's a little -- that may not be a requirement. We may be able to do all the good we need to do by just getting to Phoenix.

We are not confident, in fact are almost sure that the east line is not going to be expanded. And so what we have been working very, very hard on for the last few months is enabling other people to effectively compete with the east line, and put in a totally brand-new grassroots project from our El Paso terminal straight to Phoenix.

And so we are hoping that by this time, this summer, when we get started up, that someone will be able to get forward with that project and begin on the permitting.

One of the interesting things, too, I want to point out about the delay. It's officially, if we get up and start filling the pipe in June of this year, we're on schedule to start filling on May 31st, then our delay will have been exactly three and one-half years. The delay was not caused, necessarily, by the federal government's regulation. The delay was caused by a competitor filing bogus lawsuits and convincing a federal judge to make us do studies that the federal government had already determined we did not need to do.

And so it's an issue with the federal judge and a nasty competitor, and not necessarily the federal government. And so I did want to point that out to everyone listening, and --

PRESIDING MEMBER BOYD: Government can be good.

MR. HOBBS: Government can be okay.

In terms of our commitment to satisfy Phoenix demand, last week we had -- we invited the

State of Arizona to come to Houston and put on a workshop, at our expense, for all the Houston area refiners on how to make Phoenix grade gasoline, and to discuss with everybody the ways of getting registered to do that. We had an overwhelming attendance. There were 27 folks there from three different states, representing about 15 different refiners in Houston and in Oklahoma.

And so we're thinking the industry is behind it, and ready to get going.

So that's all I have for you.

PRESIDING MEMBER BOYD: Thank you. Anybody have any comments or questions of --

MR. LAUGHLIN: Just one thing, Horace. I agree. Horace said over time the refineries in the Gulf Coast can supply the line. I agree with that. It's the question of time that's the problem we've talked about, is 2003 a problem, and 2005 not a problem. That may actually be the case. The refiners need to see the need for the production of CARB type barrels in the future, and then work towards it.

They are tremendously flexible once they have the desire to go in that direction. Over time, I believe they'll do the same thing.

The part about the Longhorn Pipeline, though, it will develop a market over a period of time, and gradually be able to take that volume in there, instead of an MTBE ban, which would immediately need a large quantity of product.

So I agree with Horace that given the demand in that area, and especially if they're just going to make a slightly lower grade to Phoenix and Tucson, those type of barrels are readily available off the Gulf Coast over time.

PRESIDING MEMBER BOYD: Thank you.

MR. SCHREMP: Horace, I had a question.

MR. HOBBS: Sure.

MR. SCHREMP: On the grassroots looping project. You mentioned a possibility of starting permitting this summer.

MR. HOBBS: Yes.

MR. SCHREMP: Do you guys have a sense for how long that project might be from the initiation of the permitting process to completion?

MR. HOBBS: Depending on the route taken and the partners. And here again, everybody's going to see that we get up and actually get barrels, and that we can do it. It's --

optimistic, it would be two years. And that would be primarily using rights-of-way that have already had an EIS done on them. So we're redoing an EIS with no species problems, and that's the best case.

You know, here again, we'll have to watch out for competitors who don't want the line to be built.

PRESIDING MEMBER BOYD: Thank you very much.

Next?

MR. HEINE: Mr. Commissioner, my name is Bruce Heine, I'm with Williams.

A few questions before I make some comments, in regards to the extension of Longhorn from El Paso to Phoenix.

Drew, first of all, it was an excellent presentation. I learned for the second time from many things that you said today.

But on slide 61, you made a reference to that we would be octane short as a result of the MTBE phase-out and the ethanol phase-in. And while I agree in principle with that statement, if in fact the predictive model does cap the use of ethanol at somewhere around 5.7 percent by volume in Phase III, the Staff also recognized in their report that there's been a number of stakeholder comments that reference the possibility of allowing higher levels of ethanol blends through a change in the predictive model.

If that were the case, and we were allowed to blend ten percent ethanol here in California, similar to what is comparable to Arizona's wintertime program, then there would no longer be an octane problem associated with the MTBE phase-out.

And another question in regards to your presentation, Drew. On slide 65, there was a comment in regards to the RVP waiver associated with ethanol. And I didn't quite follow your point on that, and I don't have a copy of your presentation, but it was the last bullet that you made. So if I could ask you to just reiterate that point, if you would, please, I would appreciate it.

MR. LAUGHLIN: Just two points. On the first one, I agree with you. It really comes down to whether we're talking about a five percent or a ten percent ethanol level. At five percent, if we're just replacing 11 percent MTBE with five percent ethanol, we're losing ground. Okay. At ten percent, no, I agree. We got an octane balance. Okay.

As far as RVP goes, it just depends on the different RVPs, and what I'm trying to say in the different regions. We had conversations last week with Arizona at the Longhorn meeting, and it really comes down to, again, what levels of ethanol are we going to have in the gasoline, because the RVP effect at five percent and ten percent is essentially the same.

And so we're trying to discover at what level are the states going to mandate or have ethanol in the gasoline in the future. And what you're saying, I kind of agree with. If you're going to have ethanol in the system, you know, you might as well have ten percent, as long as the local rules allow it or the, you know, as far as CARB can't allow that at this point without changing CARB rules. And again, that was not part of our MTBE charge. It was to stay inside of existing CARB regulations.

But as long as the local area allows that type, amount of ethanol, yeah, it's kind of crazy to go halfway. It's either five percent if you're going to do it, you might as well go to ten.

MR. HEINE: Uh-huh.

MR. LAUGHLIN: That's the same.

MR. HEINE: Okay. And with the conventional gasoline throughout the rest of the country, that one pound vapor pressure, whatever, is still in effect and would be, even though it's been debated and is a part of the energy bill being discussed in the senate, probably today.

On to my primary comments. First and foremost, Mr. Commissioner, I'd like to support the Staff's comments in regards to their recommendations, and their general support of the Longhorn Pipeline project, their support of the expansion from the east line, or the east line from El Paso into Phoenix, and that the Commission should also support the construction of a new pipeline into Vegas.

So we're in total support of those three conclusions that your Staff has reached, and urge the Commission to come to that same conclusion.

I have mentioned before, and we have written, provided written comments in regards to the MTBE stakeholder report, that we at Williams are considering a stand-alone project from El Paso to Phoenix, and it's under review right now internally. However, if it were approved, and if we didn't run into the problems and the obstacles that Mr. Hobbs explained Longhorn ran through, we believe that that pipeline could be operating as soon as 2004.

In regards to one other issue associated with that particular pipeline project, we'd also encourage the state to recognize that there may be an indefinite delay of that particular -- or if there is an indefinite delay of the MTBE phase-out, that it would have a negative impact on the economics of the proposed pipeline, and may delay it or could derail the project entirely.

In regards to Staff's comments on asking for help from the federal government, that is a crucial part of any pipeline project, in regards to getting cooperation amongst the federal agencies. Recently, President Bush signed an Executive Order that allows the Council on Environmental Quality to coordinate amongst the federal agencies and has charged them with expediting the permitting process of pending energy projects, including pipeline projects, whether it's gas or refined products.

So I would urge that Staff and, again, the Commission adopt a recommendation for Staff to coordinate with the Council on Environmental Quality, make them aware of your recommendations in regards to the support of this new pipeline project from El Paso into Phoenix, because I think they would be keenly aware and very interested in your support of that particular project.

So again, thanks for the opportunity to present my remarks, and we support your Staff's recommendations.

PRESIDING MEMBER BOYD: Thank you very much.

Any other comments or questions? Thank you.

MR. HEINE: Thank you again.

MR. STEVENS: Good morning. My name is Jeff Stevens, I'm with Western Refinery out of El Paso, Texas. We own a refinery in El Paso that is currently operated by the Chevron Company.

I'd like to ask the Staff, they made some comments about refinery reduction or refineries closing in our area, El Paso and New Mexico, and I'd like to know what they base that on and where they got their information.

MR. LAUGHLIN: As I said, there wasn't any specific refinery noted, but the refinery rationalization that's gone on in the US, it's obvious. I mean, last week we had the Premcor closure announcement at Hartford, and we've already had Wood River go down in the middle of Chicago, one of the greatest markets there is and has proven to be in the last two years. Premcor made a conscious decision to shut down an operating refinery, rather than invest money. And it has no specific target towards your refinery or Navajo's or Giant's. It just has -- it's the fact that the probability of additional refinery closures in the United States is very high.

MR. SCHREMP: And Jeff, I'd add to Drew's comments that as I mentioned intentionally of the six refineries, some of them in western Texas are pretty large and complex. That would be your facility, as well. Others are much smaller. And so I think when there's refinery rationalization, usually what happens is some of the smaller, more high cost refineries have a difficult time to comply with new regulations, low sulfur gasoline, low sulfur diesel. And so the, you know, decline, you know, potential decline in refinery capacity would be directed at those types of facilities, not the more complex capable facilities.

MR. STEVENS: Well, I would challenge the Staff to re-look at that issue. It's been very publicly made over the last several months that the refining capacity out of El Paso, outside of Longhorn, is going to expand. Navajo made a public statement that they're going to increase their refinery by 10,000 barrels a day, that they're putting in capital to put in units to make 100 percent CARB-like gasoline.

The Phillips-Valero group has expanded and is expanding their pipeline into the El Paso market. And we've announced that we're going to expand the amount of barrels that is currently running out of that facility.

So I agree with the Staff that more product needs to come from El Paso to Phoenix in the long term. That is where the supply is going to come from. But it's not just going to come from the Longhorn project, but it's going to come from the existing refineries there. And that's really just the comment that I want to make.

MR. SCHREMP: And, Jeff, I thank you, and we'd appreciate the opportunity at, you know, some near date here, to get together and discuss some of those issues.

MR. STEVENS: Okay. Thank you.

MR. SCHREMP: Thank you.

PRESIDING MEMBER BOYD: Thank you.

Do I, should I not infer anything from your comment, Jeff, about your refinery is currently operated by Chevron?

(Laughter.)

MR. STEVENS: Our operating agreement ends in 2003. The Staff talked a little bit about low sulfur gasoline and diesel. Our refinery, we will qualify to run as a small refinery. We will have an exemption on the gasoline specs, and be able to continue to run long beyond the 2005 without major capital expenditure.

So I think you can read into it what you want, but I think that the operating agreement ends, it's publicly known, it ends in 2003. And we will continue to run our refinery at that point.

PRESIDING MEMBER BOYD: Okay, good. Thank you.

MR. STEVENS: We're not -- we're not shutting down.

PRESIDING MEMBER BOYD: All right. Thank you. I just wondered if you were telegraphing you were being swallowed by somebody else. So many of you are swallowing people these days.

All right. Anyone else in the audience?

Well, okay. Let me first say that I would like to recommend that any of you folks listening or here in the audience who want to submit written comments, please do so by March 22nd. And as indicated, we'll have another workshop. I'm beginning to think we might just have one workshop for all topics the last two days, and get on with it.

And with that, I would like to thank Drew Laughlin and the other consultants for their contribution, Staff for their presentation, and with that, we can adjourn for the day.

Have a good afternoon.

(Thereupon, the Workshop was concluded at 12:05 p.m.)

CERTIFICATE OF REPORTER

I, VALORIE PHILLIPS, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said Workshop, nor in any way interested in the outcome of said Workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 27th day of March, 2002.

VALORIE PHILLIPS